Effects of Flow Measurement Errors on Oil and Gas Production Forecast

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EFFECTS OF FLOW MEASUREMENT ERRORS ON OIL AND GAS PRODUCTION FORECASTS

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ABSTRACT

Different flow meter technologies are used to monitor the output of oil and gas wells. Although flowmeter accuracy has generally improved over time, there remain substantial uncertainties, particularly in multiphase flow. These errors could potentially be greater where older meters are being used for calibration, and/or maintenance is difficult. Consequently, the associated errors with the recorded data could be out of specification in such cases. One use of the well flow data is to improve parameter estimates for important characteristics of reservoirs such as porosity and permeability. Therefore, any errors in flow measurement influence the results of a reservoir simulation and production forecasts. However, the impact of flow measurement errors on the forecast of oil and gas production has not been considered before. In this study, the effects of using out-of-specification errors on the predicted reservoir production have been investigated. As a test case, the simulated production results of a reservoir with known characteristics were considered to be the actual flow rate values. Then, two sets of data were generated by applying errors up to 5% and 10%, respectively, to the flow rates and the resulting values were used in a history matching exercise to modify the predictions of the simulations for the same reservoir with incorrect porosity and permeability parameters. The errors in the first and second sets of data were considered to be within and without the specification, respectively. The results show that when errors are within the specification, the corrected porosity and permeability values have less than a 2.2% and 2.5% error, which cause minor deviations of up to 2.3% in the production forecast. However, for the second set of data, when the errors are increased up to 5% more than the specification, the corrected porosity, permeability and production forecast deviate significantly up to 10.8 %, 10.1% and 12.4% from their respective reference values.
Keywords: flow meters, flow measurement errors, history matching, reservoir simulation.

1 INTRODUCTION

Reservoir oil and gas production forecasts provide essential information for reservoir management and decision making [1]. These forecasts help engineers to determine how much oil and gas will be available to be sold in the market. They are also used to make decisions about production scenarios. As a consequence, these estimations indirectly affect the ultimate hydrocarbon recovery from a reservoir by affecting the decision-making process [2]. Therefore, an accurate production forecast is one of the most important responsibilities of a reservoir engineer. In the past, production forecasts were being done by hand calculations. However, this process was time consuming and not precise enough in some cases. At present, the development of reservoir simulators has made production forecasting much easier. Many reservoir simulators have been developed by different companies, universities and research centers. The majority of them are commercially available or have been presented in the literature [3]–[10]. Regardless of how precise these simulators are, the uncertainties in the measured reservoir characteristics which are used as their inputs may cause errors in the production forecast [11], [12]. Some of the parameters used in the simulators to build the reservoir model are the measured characteristics of reservoir fluids and rocks, and these are normally determined by taking samples from the wells. However, since reservoirs are inexorably heterogeneous in their characteristics, the characteristics of the fluid and core

WIT Transactions on Engineering Sciences, Vol 115, © 2017 WIT Press
www.witpress.com, ISSN 1746-4471 (on-line)
doi:10.2495/MPF170141

samples taken in a limited number of wells are not representative of the average characteristics of the reservoir [13]. Consequently, reservoir engineers assess the precision of the simulation results against the measured production data of the reservoir to make sure if the simulated model represents the actual reservoir properly. Then if they observe a deviation between the two, they modify the value of the uncertain characteristics in their model so that they get the best possible match between the simulation results and the actual production data. In other words, in this process, referred to as history matching, they try to make the simulation model more representative of the actual reservoir. Fig. 1 presents the procedure of production forecast including history matching. Different methods for history matching have been presented in the literature so far [14]–[16]. These methods use measured production rates as their reference values for history matching. However, since any flowmeter inevitably has a percentage of error in its measurements, no set of measured values is exactly the same as the actual reservoir production data. Therefore, in reality the simulation results are assessed against a set of data which includes uncertainty itself. These uncertainties affect reservoir model modifications and consequently the resulting production forecasts. However, this issue has thus far not been addressed comprehensively in the literature.

This study attempts to address that dearth of information, in that the effects of flow measurement errors on production forecast have been investigated. This has been achieved through the use of a well-known reservoir simulator to model a hypothetical reservoir with known characteristics that has been created specifically. This model created is considered to be the reference model in this work. Therefore, the simulated production results of the model have been considered to be the actual production data from the reservoir. Consequently, a new set of data has been created by applying a specified percentage of error to the actual production data bounded but randomly generated numbers. This new data set has subsequently been considered to represent the measured production data for a flowmeter with a specified measurement error. In the next step, the values for two important characteristics of the reservoir (i.e. average porosity and permeability) which always include uncertainties have been changed in the reference model to create an incorrect reservoir model. Then the incorrect model has been modified in a history matching using the measurement data. Finally, the modified model based on the measurement data has been used to forecast the production and its results have been compared with the production forecast results of the reference model. The difference between these two sets of results shows how measurement errors can affect estimations of future oil and gas production.

2 METHODOLOGY

A hypothetical saturated oil reservoir with known characteristics has been simulated using the Schlumberger ECLIPSE [10] oil industry reference simulator. The reservoir model, its characteristics and its simulation results are considered to be the reference values (i.e. actual values) in this work. The reservoir considered is a layer with a thickness of 30.48 meters (100 ft.) and a total volume of 2.8E8 cubic meters. The characteristics of the reservoir rock and fluid are shown in Table 1.

There is assumed to be no water influx into the reservoir while the producing well is considered to be drilled in the middle of the reservoir and perforated along all of the depth of the pay zone. A 10-year period of production has been simulated for this reservoir while the production control has been set to 1500 psia bottom-hole pressure. The oil and gas production results from the simulator model of this period have been considered to be the actual production data (or reference values) in this work.

Two different groups of data were created by applying up to 5% and 10% error to the reference oil and gas production values, using randomly generated numbers (Table 2). These groups of data represent values measured by flow meters with different levels of accuracy. In reality, flow measurement data are used in history matching to modify the predictions of future production by comparing the reservoir simulation results with the flow measurement. Each data group consists of three data sets: the first being the errors that are applied in the both positive and negative directions; the second set being the errors only in the negative direction and in the third set only errors in the positive direction. The two latter situations represent the situation when flowmeters systematically underestimate or overestimate the production flow rates. The details of the generated data sets are shown in Table 2. The errors in Group 1 and Group 2 are considered to be within and without of the specification, respectively.

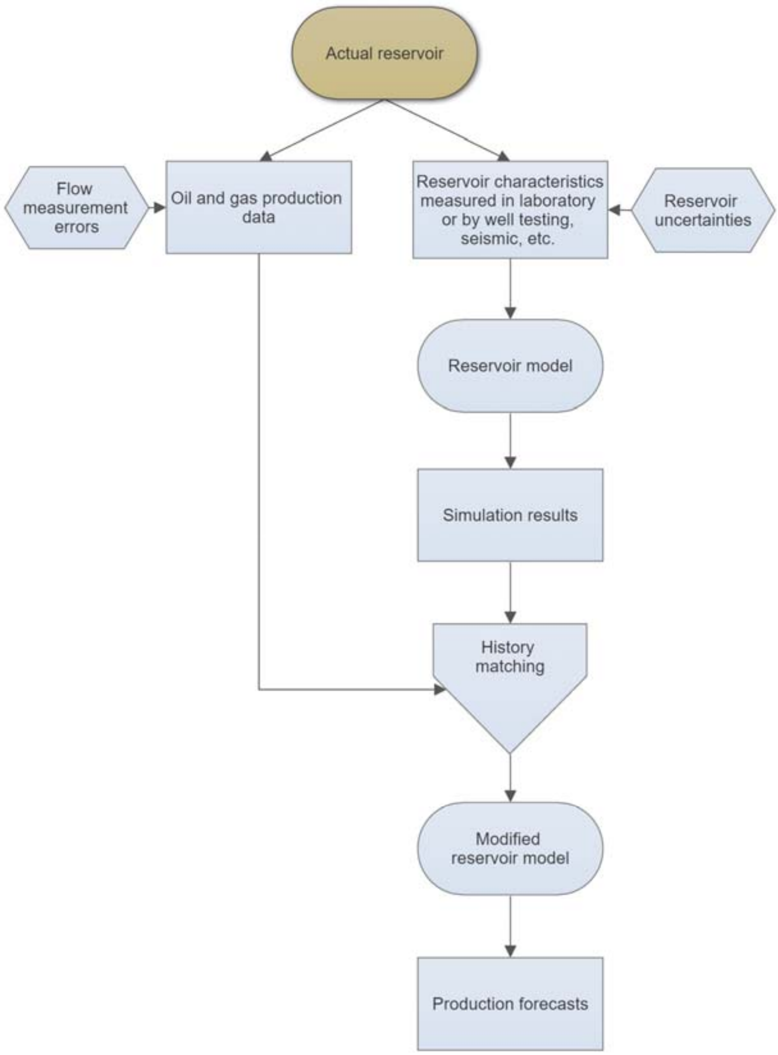

Figure 1: The procedure of production forecasts. No comprehensive work on the effect of flow measurement errors on this procedure is published in the literature so far.

Table 1: The reservoir rock and fluid characteristics.

Initial reservoir pressure	4412 psia
Porosity	0.18
Horizontal permeability	60 mD
Vertical permeability	10 mD
Saturation pressure of the reservoir fluid	5600 psia

Table 2: The generated flow measurement data sets.

Group	Set	Error Range
A	A.1	-10% to +10%
	A.2	-10% to -5%
	A.3	+5% to +10%
B	B.1	-5% to +5%
	B.2	-5% to 0%
	B.3	0% to +5%

In the next step, the porosity and horizontal permeability were changed to 0.24 and 110 mD, respectively, to create an incorrect reservoir model. Notice that in reality almost always the reservoir models do not completely represent the actual reservoir because there are always uncertainties in measured or calculated reservoir characteristics. Therefore, it has been considered that this incorrect model is created based on uncertain values of porosity and permeability and should subsequently be modified by history matching using flow measurement data. It should be added that based on our simulations, the initial values chosen for the incorrect porosity and permeability have no effect on the results of history match and therefore any other incorrect values would lead to the same results. Based on the incorrect model, the simulations were run using the same production control as the reference case and then history matching was performed using all six generated data sets. Therefore, for each data set, modified values were obtained for the porosity and permeability and compared to their respective reference values. In the final step, the reservoir model was simulated for an extraction period of 30 years by employing the modified values. The calculated oil and gas production values based on modified model were then compared to those of the reference model. This comparison can show the deviation between the modified results and the reference results for a further 20 years of oil and gas production forecast after the 10-year history matching period. The deviation between these two sets of results is a consequence of the applied errors in the data. In the reality, this deviation represents the effect of flow measurement errors in recorded oil and gas production flow rate equipment which are used as observed values in the history matching.

3 RESULTS AND DISCUSSION

The procedure of history matching for all data sets is the same. Therefore, in this section, the history matching plots for Data set A.1 have been shown and explained in detail as an example of all history matches. Then the results of all data sets have been presented and compared in Table 2 and Fig. 2.

The data in Group A represent the measurements of a flowmeter with a 10% error. We have defined three scenarios for this group. In the first scenario (Data Set A.1), the errors range from -10% to +10% of the actual value. In other words, the flow meter randomly underestimates or overestimates the flow by 10%. The results of the simulations for the incorrect reservoir model and Data Set A.1, which is used as the observed data for the history matching, are shown in Figs 3 to 5 for oil, gas and water production, respectively. As normally happens in the first simulations undertaken after starting production from a new reservoir, the simulation results do not match the observed data. Since the permeability in the simulated model (110 mD) is more than its reference value (60 mD), the predicted production rates are greater than the observed data.

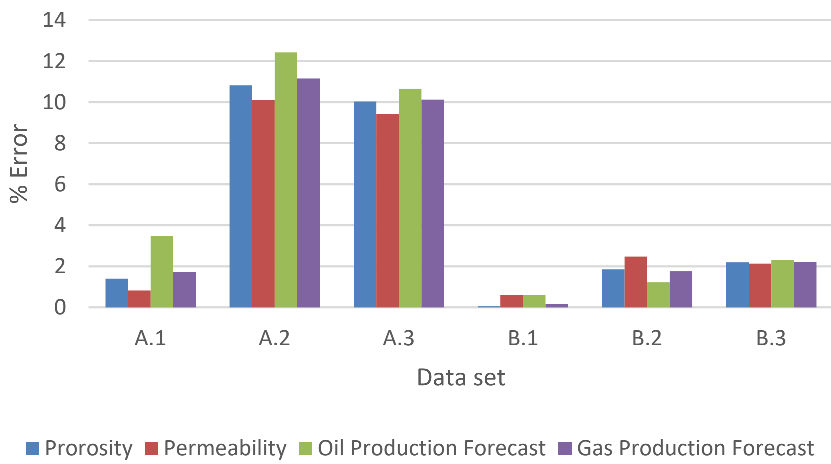

Figure 2: The comparison between the results of different data sets.

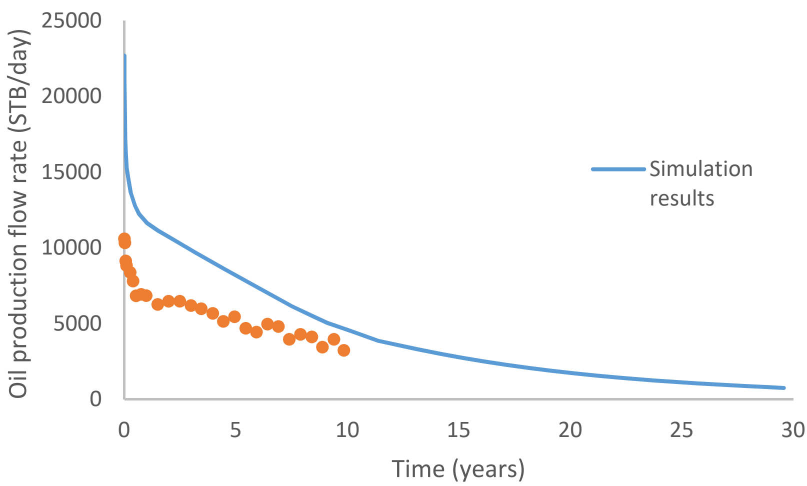

Figure 3: The simulated oil production curve and the measured oil production data points (before history matching).

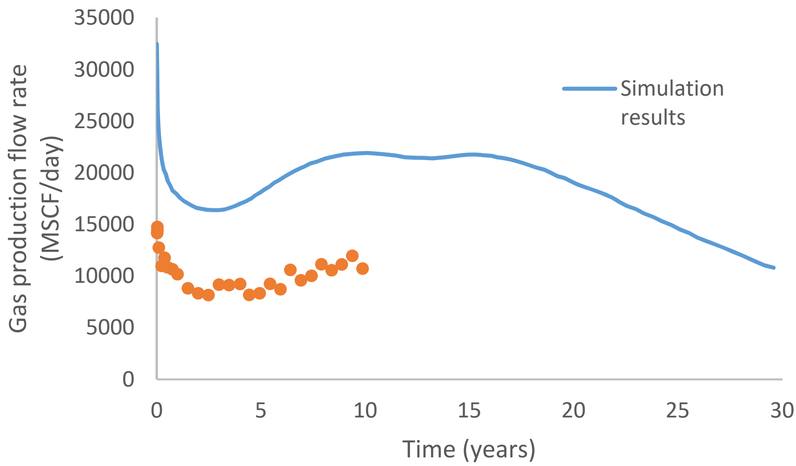

Figure 4: The simulated gas production curve and the measured gas production data points (before history matching).

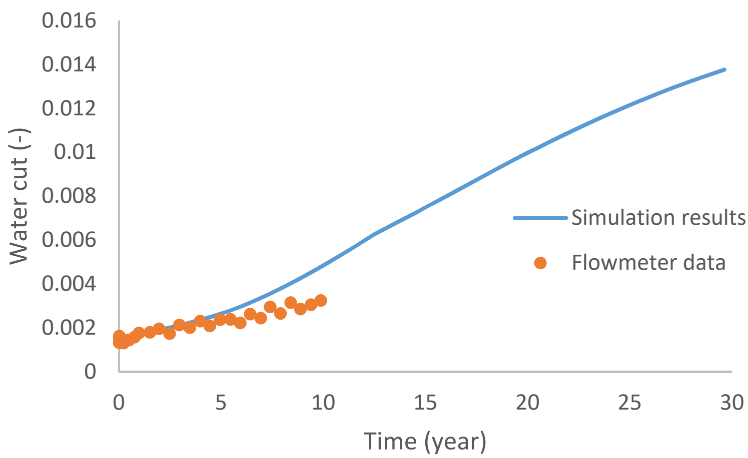

Figure 5: The simulated water production curve and the measured water production data points (before history matching).

In order to make the simulation model more representative of the reference reservoir, the uncertain characteristics of the reservoir need to be modified by matching the simulation results against the observed data. Therefore, in the next step a history matching was undertaken using the simulation results and the data set. The porosity and permeability which have led to the best match by minimizing the total root mean square have been reported as the modified porosity and permeability. The results for the best matches are shown in Figs 6 to 8.

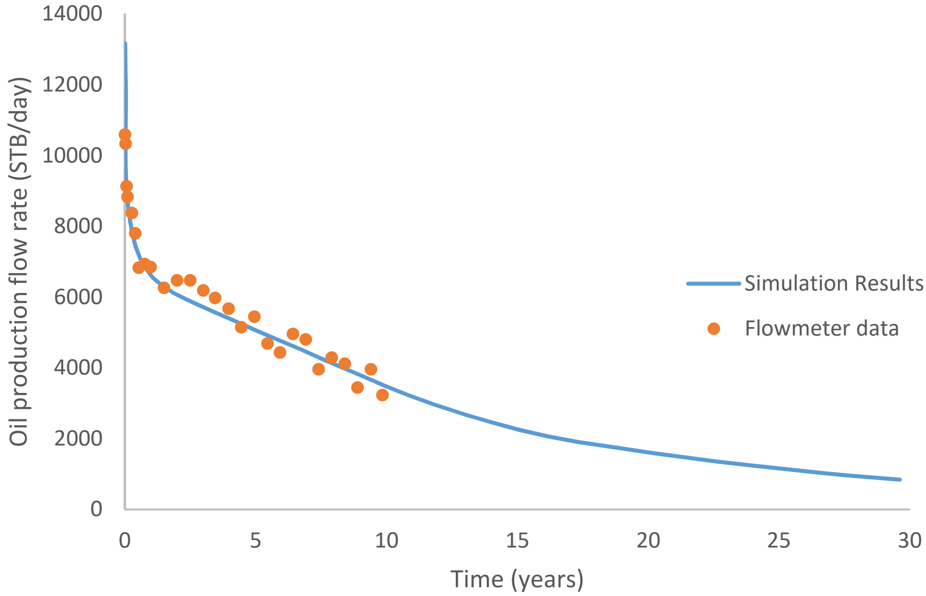

Figure 6: The simulated oil production curve and the measured oil production data points (after history matching).

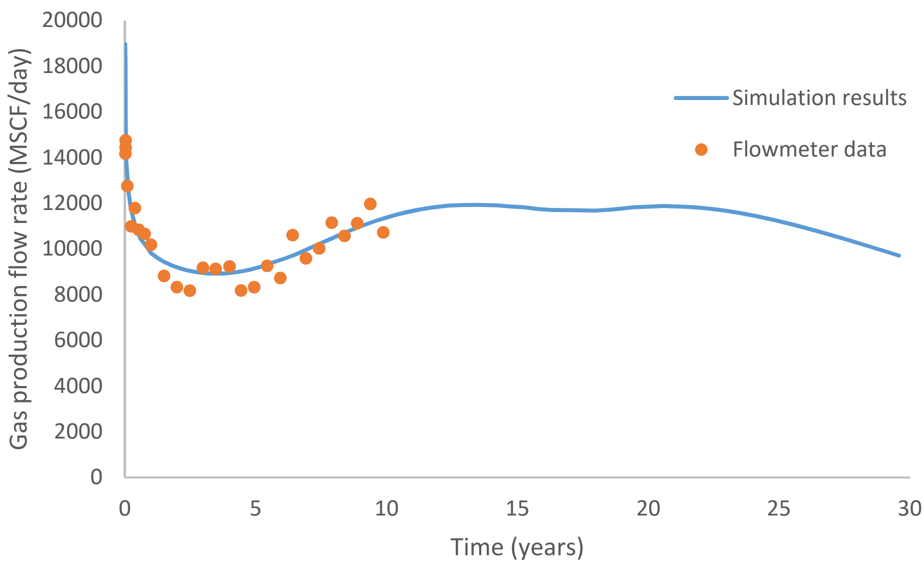

Figure 7: The simulated gas production curve and the measured gas production data points (after history matching).

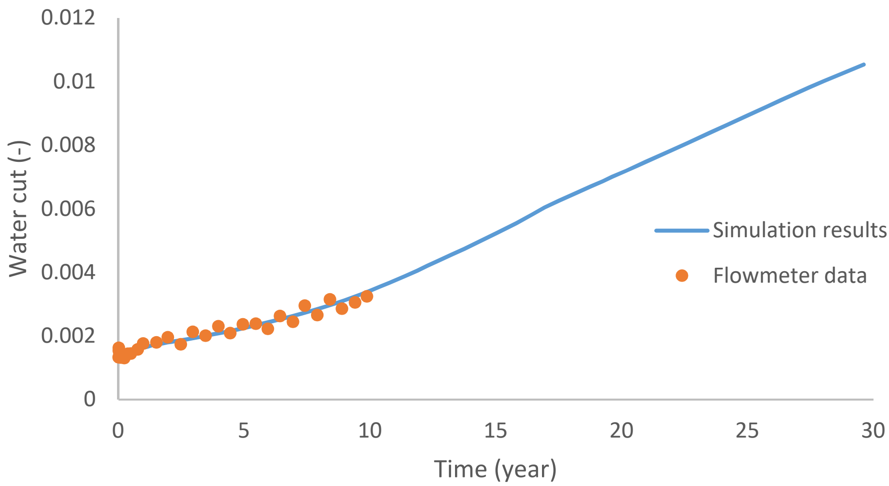

Figure 8: The simulated water production curve and the measured water production data points (after history matching).

The modified porosity and permeability obtained from this match are 0.1825 and 59.51 mD, respectively. Therefore, compared to their respective reference values, which are 0.18 and 60 mD, the deviations are the insignificant values of 1.40% for the porosity and -0.82% for the permeability. Also, the comparison between production rate forecasts for the modified and reference models show that after 30 years the errors are 3.49% and 1.72% for the oil and gas rates, respectively. The minor errors in predictions for this scenario show that when measurement errors are distributed in both negative and positive direction, their effects may cancel out each other and as a result we may obtain a satisfactory match. However, if the errors are just in one direction (negative or positive) they may lead to different results. Errors in one direction may occur when a flowmeter either underestimates or overestimates the flow rates.

To investigate the effects of overestimations or underestimations of flow rates, Data Sets A.2 and A.3 (Table 2) were generated by applying up to 10% error just in one direction (negative or positive) to the reference production data. In addition, another group of data sets was created with maximum possible error of 5% (Group B in Table 2) to help us find out the effect of reducing the measurement errors on the history match results. As with Group A, Group B has also been divided into three data sets based on the same assumed scenarios regarding the direction of the errors. We have considered the specification for errors to be 5%. Therefore, the comparisons between the results of the two data groups show us how the future production forecasts can be affected when errors are out of the specification for just 5%. Table 3 and Fig. 2 include the results of the history matches for all data sets.

The resulting values for Data Sets A.2 and A.3 are significantly greater than the results of Data Set A.1. This observation indicates how the direction of the errors can considerably affect the modified model and estimated future production. Since the errors in Data Set A.1 are distributed in both directions, the errors cancel out the effect of each other; deviating the plot from its correct position. However, when errors are just in one direction, they boost the effect of each other in deviating the matched production curve from its correct position.

Table 3: The results of the history matchings and production forecasts.

Data Group	Data Set	Error Range (%)	Porosity Error (%)	Permeability Error (%)	Oil Production Error (%)	Gas Production Error (%)
A	A.1	-10 to 10	1.40	-0.82	3.49	1.72
	A.2	-10 to -5	-10.82	-10.11	-12.42	-11.15
	A.3	5 to 10	10.03	9.42	10.65	10.12
B	B.1	-5 to 5	-0.05	0.61	-0.61	-0.16
	B.2	-5 to 0	-1.85	-2.47	-1.22	-1.76
	B.3	0 to 5	2.19	2.13	2.31	2.20

Therefore, a flowmeter which either underestimates or overestimates the flow causes greater errors in the modification of a reservoir model or estimation of future production. Comparing the results of Data Sets B1, B2 and B3 also leads to the same outcome and completely supports this conclusion.

A comparison between the results of Data Group A and Data Group B indicates the effect of a 5% reduction in the measurement errors on the forecast of production. All of the resulting errors for the data sets of Group B are less than the correspondent errors for the data sets in Group A. While the resulting errors for all data sets of Group B are in an acceptable range, the errors for Data Sets A2 and A3 are significant. In other words, if we consider that the specification for the error is 5%, as long as the measurement errors are less than the specification, the resulting history match errors remain in an acceptable range even in the case of the underestimation or overestimation. However, if the measurement errors fall out of the specification for only 5%, the history match results are highly affected, especially in the case of the underestimation or overestimation.

4 CONCLUSIONS

In this work, the effects of flow measurement errors on the precision of history matching of oilfield reservoir production results were investigated. Using a model of a hypothetical reservoir, several possible sets of flow measurement data were generated based on two different flow meter error specifications. These data were used in history matching to modify the assumed reservoir model parameters. Finally, the production forecast results of the modified model were compared with those of the reference model to determine the effects of the flow measurement errors on the production forecast.

The results show that those meters which underestimate or overestimate flow rates and consequently cause errors just in one direction have a more negative effect on history matching compared to those with errors in both directions. However, it was found that if the flowmeter errors are within the specification of 5%, the precision of the oil and gas production forecasts are seen to be reasonable even in the case of flow rate underestimation or overestimation. Under these circumstances, the greatest error in forecasts is 2.31%, in this case for oil production. The other results show that if the flow measurement errors are increased up to five percent more than the specification, the forecast errors may be increased up to 12.42% for oil production. The results show that in the case that flow measurement errors have had a random distribution of 10% in both directions, they have cancelled out the negative effects of each other and the final results for forecasts are acceptable. However, for both cases of underestimation and overestimation the final errors are significant.

This paper demonstrates the impact of flow measurement errors on oil and gas production forecasts. The recommendation for future studies is to provide a guideline which determines the acceptable flow meter error specification for each reservoir type. Such a guideline will help preventing flow measurement errors to cause extra costs by affecting the precision of production forecasts.

ACKNOWLEDGEMENTS

The authors would like to thank Professor Manus Henry from Oxford University and Dr. Philip Costen from Coventry University for their valuable comments on this article.

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